National Energy Board

Office national de l'énergie

Short-term Canadian **Natural Gas** Deliverability

2004 - 2006

An **ENERGY MARKET ASSESSMENT** • November 2004

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Acronyms

B.C.	British Columbia
EMA	Energy Market Assessment
NEB	National Energy Board
NGC	Natural Gas from Coal
SOEP	Sable Offshore Energy Project
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= Gigajoule

Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C)	= 35.3 MMcf (@ 14.73 psia and 60° F)
1 GJ	= 0.95 Mcf

FOREWORD

As part of its mandate under the *National Energy Board Act*, the National Energy Board (NEB or the Board) is required to study and keep under review a broad range of energy matters over which Parliament has jurisdiction. In keeping with this responsibility, the Board continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and natural gas liquids) and the demand for Canadian energy commodities in both export and domestic markets. The Board publishes reports on energy, known as Energy Market Assessments (EMAs), which examine various facets of Canada's energy market. These reports include both long-term assessments of Canada's energy future and specific reports on current and near-term energy market issues.

In addition to its mandate to monitor energy markets in Canada, the Board has specific monitoring responsibilities pursuant to its regulatory responsibilities. The Board is required to monitor Canadian energy markets to ensure that markets are operating such that Canadian energy requirements are being met at fair market prices.

This EMA report, titled *Short-term Canadian Natural Gas Deliverability, 2004-2006*, examines the factors which affect gas supply in the short-term and presents an outlook for deliverability through to the year 2006. The main objective of this report is to advance the understanding of the short-term gas supply situation by examining recent trends in the production characteristics of the Western Canada Sedimentary Basin (WCSB) and the east coast offshore and applying these trends to provide an outlook for short-term Canadian deliverability. Further, this report is an update to the Board's December 2003 EMA, titled *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin, 2003 - 2005*.

During the preparation of this report, meetings and discussions were conducted with natural gas producers, pipeline companies and industry associations. The Board appreciates the information and comments it received.

Questions and comments regarding this EMA may be referred to either:

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OVERVIEW

For much of this decade, North American natural gas markets have experienced an extremely close balance between supply and demand. Since 2001, supply growth has stalled and demand has had to be reallocated to accommodate market growth. These tight market conditions have been contributing to high and volatile natural gas pricing. Over the last year, a dramatic increase in oil prices has exacerbated the upward movement in gas prices by reducing fuel switching opportunities. In such a tightly balanced market, the critical role of Canadian gas supply takes on even greater importance. The objective of this assessment is to provide an outlook for Canadian natural gas deliverability through to the end of 2006.

Rising Canadian gas production was able to satisfy a substantial portion of U.S. demand growth throughout the 1990s, and now accounts for almost one-quarter of the gas consumed in the two countries[1]. Since 2001, Canadian production has stayed stubbornly flat despite strong pricing and record-breaking drilling activity.

Almost 98 percent of Canadian gas is produced from the Western Canada Sedimentary Basin (WCSB) with Alberta accounting for roughly 80 percent of the output. British Columbia and Saskatchewan contribute roughly 16 and four percent of the total respectively. Conventional gas in the WCSB will remain the mainstay of Canadian gas production through the projection period, but increasing interest is being shown in the commercial development of natural gas from coal (NGC)[2]. Since the start of the decade, gas production from offshore Nova Scotia has established a vital regional presence serving domestic gas consumption in the Maritimes and export markets in the U.S. northeast. For this assessment, separate deliverability estimates are provided for conventional gas in the WCSB, NGC and offshore Nova Scotia.

The Board expects average annual Canadian gas deliverability to rise slightly over the period from 469 million m^3/d (16.6 Bcf/d) in 2003 to 473 million m^3/d (16.7 Bcf/d) in 2004 and to 477 million m^3/d (16.9 Bcf/d) by 2006. WCSB conventional gas and offshore Nova Scotia maintain deliverability levels around 456 million m^3/d (16.1 Bcf/d) and 11 million m^3/d (0.4 Bcf/d) respectively over the period. The slight increase in deliverability is largely attributable to an expected rise in NGC deliverability from 3 million m^3/d (0.1 Bcf/d) in 2004 to 11 million m^3/d (0.4 Bcf/d) in 2006.

With production and decline rates fairly stable in conventional areas of the WCSB, a similar amount of deliverability will need to be replaced each year through new well connections. However, the average initial productivity of new well connections in conventional gas areas of the WCSB continues to trend downward. To offset the slippage in productivity, an increasing number of new gas well connections are needed each year to maintain conventional WCSB deliverability.

1. Canadian gas supplies virtually all domestic requirements as well as roughly 16 percent of U.S. requirements.
2. Also known as coal bed methane or CBM.

The number of NGC wells to be drilled is expected to increase significantly over the period as the scale of development expands from its initial stage. One additional field is expected to be brought into production offshore Nova Scotia to join the four producing fields.

In summary, the modest increase in Canadian gas deliverability is expected to be achieved through increases in drilling activity from 15,100 gas wells drilled in 2003 to an expected 15,600 in 2004 and 17,900 in 2006. The majority of these wells are in conventional gas areas in the WCSB. Canadian natural gas prices are expected to remain above the $4.75/GJ ($5.00/Mcf)[3] level over the period and provide sufficient cash flow to fund the anticipated activity levels.

3. All prices in this report are denominated in current Canadian dollars at the AECO Hub in Alberta.

INTRODUCTION

Canada is an important source of natural gas supply in North America accounting for almost one-quarter of the combined production of Canada and the United States in 2003. Due to Canada's substantial role in North American natural gas supply, there is considerable interest in the outlook for Canadian gas production over the next few years. The primary objective of this report is to provide the Board's current outlook for Canadian natural gas deliverability to the end of 2006.

Previous EMAs on the topic of short-term deliverability dealt exclusively with natural gas from western Canada. This assessment supplements the analysis of western Canada by examining deliverability from offshore Nova Scotia. As well, with the growing interest and rapid developments surrounding NGC, an increased emphasis has been placed on NGC in western Canada. The assessment also examines the impact of stronger prices and increased revenues for the upstream sector on gas drilling and deliverability.

Chapter 2 provides background on Canadian supply, including a description of the geographic extent and nature of the supply in each region. Also included is a discussion of recent regional production trends.

Chapter 3 describes the approach used to estimate Canadian gas deliverability. The approach includes the analysis of production decline trends by region to estimate future deliverability from existing wells. The chapter also describes how the production characteristics of the more recently connected wells are used to estimate initial productivity and decline rates for future gas well connections. The development of the cash flow estimates and the corresponding drilling outlook are also described.

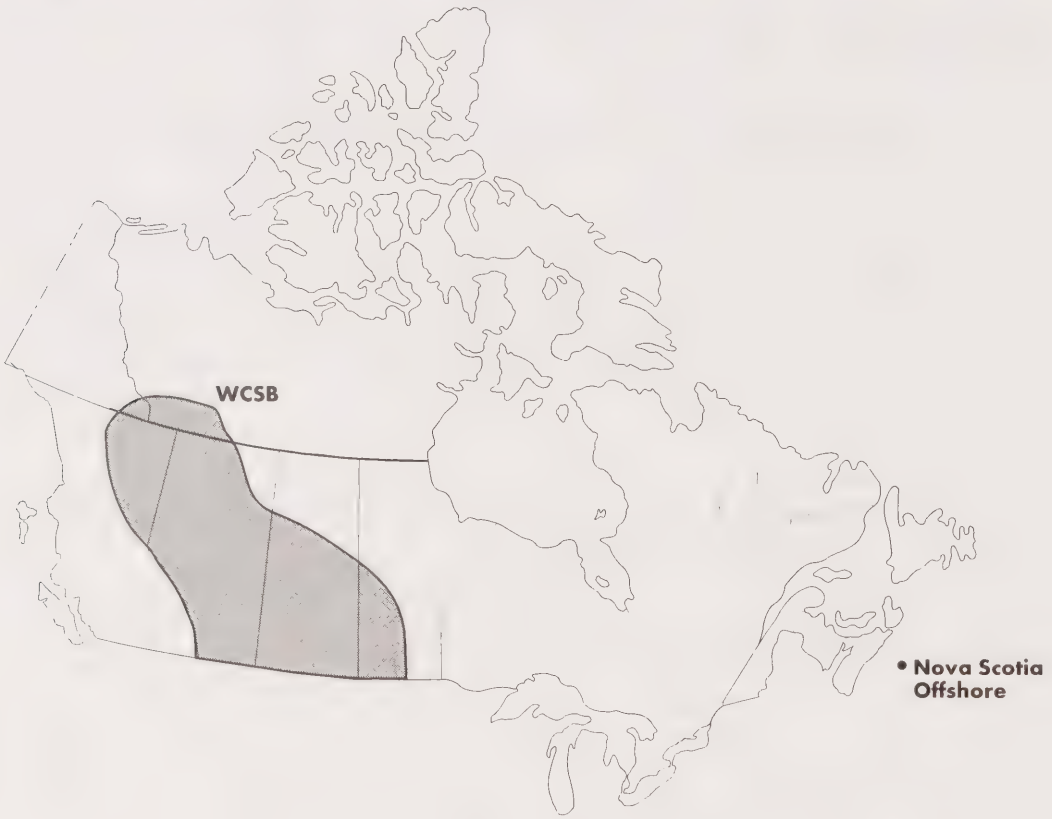
Chapter 4 provides the results of the regional deliverability analyses including the estimated production characteristics for currently producing and future gas wells, and the number of gas well connections expected over the projection period.

The Board's outlook for Canadian natural gas deliverability is presented in Chapter 5. The conclusions and possible implications of the assessment are discussed in Chapter 6.

BACKGROUND

The Western Canada Sedimentary Basin (WCSB) has traditionally been Canada's main source of gas production and it currently accounts for 98 percent of total Canadian production. Natural gas production from offshore Nova Scotia commenced at the end of 1999 and provides most of the remaining gas production in Canada[4]. Figure 2.1 shows the location of these gas producing areas. Descriptions of the significant features of the regions and a summary of recent production follow.

Canadian Gas Producing Areas



4 Minor amounts of gas production occur in other parts of the country including southern Ontario and New Brunswick. These minor production volumes are not addressed in this assessment.

2.1 WCSB – Conventional Gas Supply

The WCSB underlies most of Alberta, significant portions of British Columbia (B.C.) and Saskatchewan, as well as parts of Manitoba and the Yukon and Northwest Territories (Figure 2.1). Alberta accounts for the largest share of production at roughly 80 percent. British Columbia and Saskatchewan provide roughly 16 and four percent of the total respectively. The Yukon and Northwest Territories currently contribute less than one percent of WCSB production and there is currently no production in Manitoba.

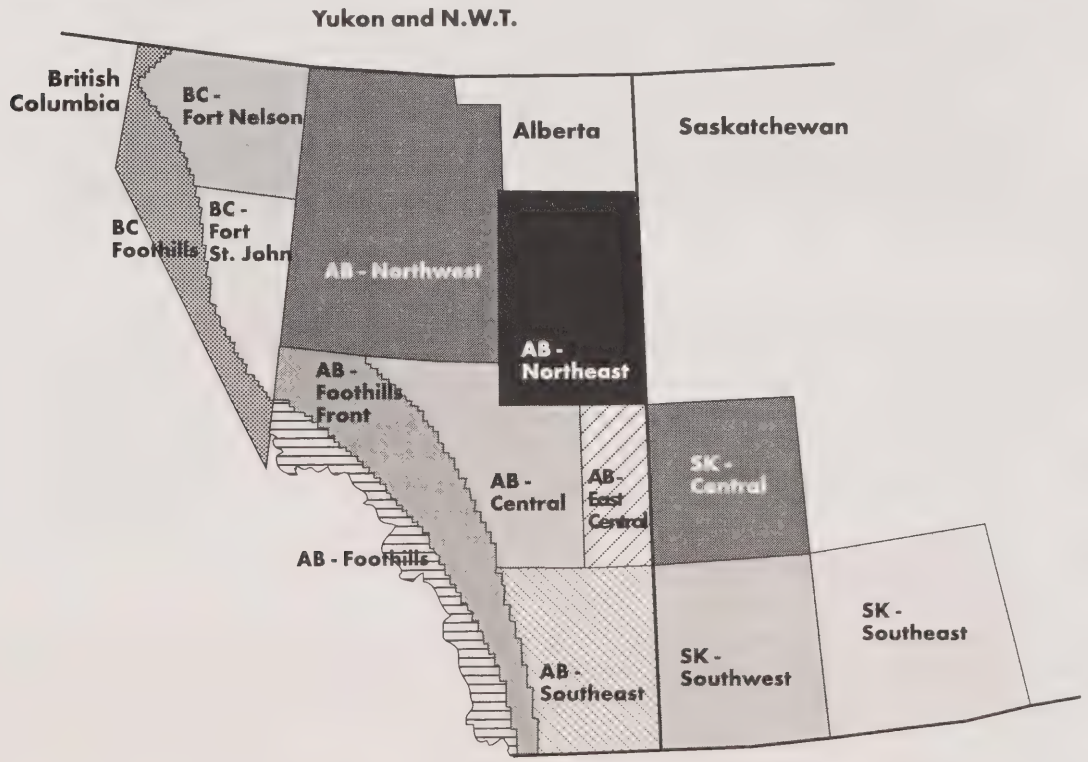
The large regional differences in physical and producing characteristics within the WCSB require that the basin be divided into smaller areas with similar characteristics for production decline analysis. For this assessment, the WCSB has been split into 14 geographic regions based on similar producing characteristics, as shown in Figure 2.2.

WCSB monthly gas production by connection year is shown in Figure 2.3. Gas production from the WCSB has been stable for the past few years at around 450 million m^3/d (16 Bcf/d) as high levels of drilling activity have been offset by higher decline rates and lower productivity of new wells. The increasingly vital role of new drilling is also evident, with roughly 50 percent of 2003 production provided by wells that have been on production for five years or less.

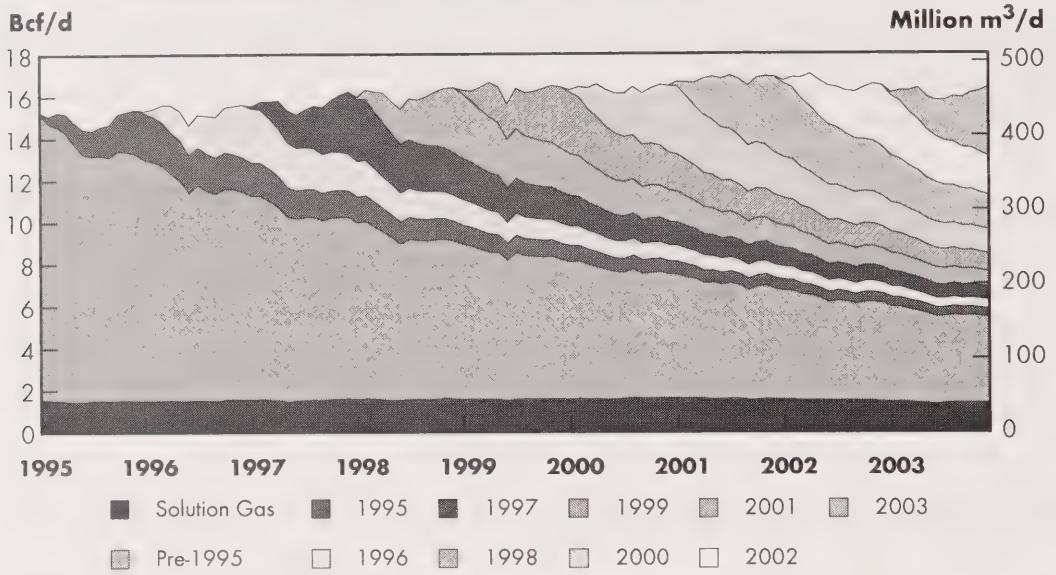
2.2 WCSB - Natural Gas from Coal (NGC)

Natural gas from coal is an emerging supply source in Canada. Coal deposits containing natural gas exist in many regions across the country, but development of the resource is in its infancy. Most

Study Areas in WCSB



WCSB Historical Conventional Gas Production by Connection Year



Source: GeoScout Well Production Records with Board Estimate of Shrinkage Applied

of the NGC activity is in Alberta where the majority of the resource is located and where NGC development benefits from the availability of extensive existing infrastructure. Commercial NGC production is underway in some areas of Alberta, while still in the experimental stage in other parts of the province and in B.C.

The two main geologic sources of NGC are the Horseshoe Canyon and Mannville coals. Production of NGC is currently from Horseshoe Canyon coals in south central Alberta. Horseshoe Canyon coals have relatively low concentrations of natural gas but benefit from being fairly shallow, dry and more permeable than other coals. The deeper Mannville coals represent a larger potential resource, but development remains in the experimental stage. Mannville coals have a higher concentration of natural gas, but will be more costly to develop because they are deeper and contain large quantities of saline water that must be produced and re-injected into deeper formations before gas production could begin. No commercial production of gas from Mannville coals is expected within the projection period.

NGC production in Alberta was about 2.1 million m^3/d (75 MMcf/d) at the end of 2003. By mid-2004, NGC production volumes had reached approximately 2.8 million m^3/d (100 MMcf/d). Virtually all production is from Horseshoe Canyon coals. It should be noted that production from NGC wells may also include some volumes of conventional gas as the coals are often interbedded with conventional gas reservoirs. In contrast to the rapid declines of conventional shallow gas wells, early indications suggest that NGC wells may produce for up to 30 years with very gradual declines.

2.3 Nova Scotia Offshore

Since the start of the decade, gas production from offshore Nova Scotia has established a vital regional presence by providing energy consumers in the Maritimes with their first opportunity to use natural gas. As well, this supply source has provided significant exports to the U.S. northeast.

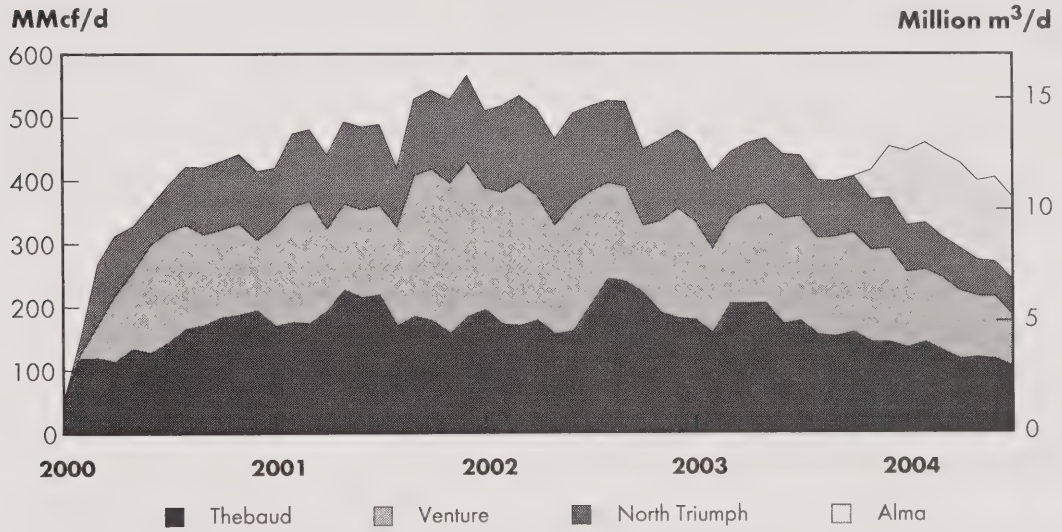
Nova Scotia offshore production is delivered from the Sable Offshore Energy Project (SOEP). The project commenced production at the end of 1999 and currently accounts for about 11 million m^3/d (400 MMcf/d) or about two percent of Canada's natural gas deliverability.

The three original fields of the SOEP have been experiencing natural production declines ranging from 28 to 34 percent since the start of 2004, as indicated in Figure 2.4. The connection of a fourth field, Alma, in late 2003 added 3.7 million m^3/d (130 MMcf/d) of production and offset the declines from the other fields through March. Between March and August, gas production from the Sable project slipped from about 12.5 to 10.8 million m^3/d (440 to 380 MMcf/d).

The higher cost of offshore operations means that, when compared to onshore projects, offshore projects typically involve relatively few wells producing at fairly high rates. This tends to make deliverability more variable as aggregate production can be significantly affected by the performance of a few wells. Since the Maritimes region is reliant on a single offshore project, regional deliverability has also experienced significant variability. This is expected to remain a challenge to market participants as deliverability will continue to vary with natural field declines, the addition of a new field and added field compression over the period.

FIGURE 2.4

Nova Scotia Offshore Gas Production



Source: Canada Nova Scotia Offshore Petroleum Board (with factor of 0.96 applied to convert from raw to marketable gas).

METHODOLOGY

Future Canadian natural gas deliverability will primarily consist of conventional gas supply from the WCSB with contributions from offshore Nova Scotia and, increasingly, from NGC in western Canada. In this EMA, trends in average production characteristics are used to determine conventional natural gas deliverability from the WCSB. The estimation of NGC deliverability is further complicated from conventional gas data in the basin due to the sparse NGC production history. To compensate for the limited production data, the Board consulted with industry to obtain views on possible production profiles.

A different approach is used for the Nova Scotia offshore where production history is obtained from a small number of wells from clearly defined fields. Production from the Nova Scotia offshore is sourced from one large project and the projection period is likely to see the connection of only one additional field. The estimate of Nova Scotia offshore gas deliverability focuses specifically on the SOEP.

3.1 WCSB – Conventional Gas Supply

The method used in this EMA to determine gas deliverability from the WCSB can be summarized as follows:

Future Deliverability = [Future Deliverability from Existing Gas Well Connections] + [Deliverability from Future Gas Well Connections] + [Solution Gas Deliverability]

The above formula is applied to each of the geographic areas identified in Chapter 2 to obtain an estimate of short-term deliverability for the WCSB.

For the purpose of this report, *Existing Gas Well Connections* are considered to be those brought on stream prior to January 1, 2004, and *Future Gas Well Connections* are considered to be those brought on stream after January 1, 2004.

To obtain an estimate of **Future Deliverability from Existing Gas Well Connections** in each geographic area, gas well connections were grouped by connection year and production decline analysis was performed to determine the parameters that define the future deliverability of the group.

To estimate the **Deliverability from Future Gas Well Connections**, production decline analysis was performed on production data for the "average gas well connection" in each geographic area[5]. The analysis done on the average gas well connections is very similar to that performed for existing

5 In estimating the average gas well connection, the production history data is normalized by using the number of months since the start of production.

gas well connections, except that the focus is more on defining the production characteristics in the earlier stages of production, rather than emphasizing the most recent production history. The trends seen in the historic data were used to establish parameters that define the deliverability to be expected from future gas well connections. The number of gas well connections expected in future years is estimated and applied to the expected productivity of the typical gas well connection of future years to obtain the Deliverability from Future Gas Well Connections.

Solution Gas Deliverability refers to natural gas produced in conjunction with oil production. Historical natural gas production data was totalled for all oil well connections within each geographic area, and production decline analysis was performed to obtain the parameters which define Future Solution Gas Deliverability.

All connections that produce gas and/or oil were categorized as either gas ("gas well connections") or oil ("oil well connections") based on each connection's cumulative production and cumulative gas-oil ratio. NGC is included in "gas well connections", but this resource is assessed separately from gas well connections producing from conventional sources.

3.1.1 *Existing Gas Well Connections*

Within each producing area of Alberta, B.C. and Saskatchewan (except for the Southeast area of Saskatchewan where only solution gas is produced) gas well connections were grouped by connection year and production decline analysis was performed on each grouping.

For each grouping of gas well connections (grouped by geographic area and connection year), the total marketable gas production for each calendar month was calculated and a plot of group production rate versus cumulative production was constructed to determine the following parameters for each group:

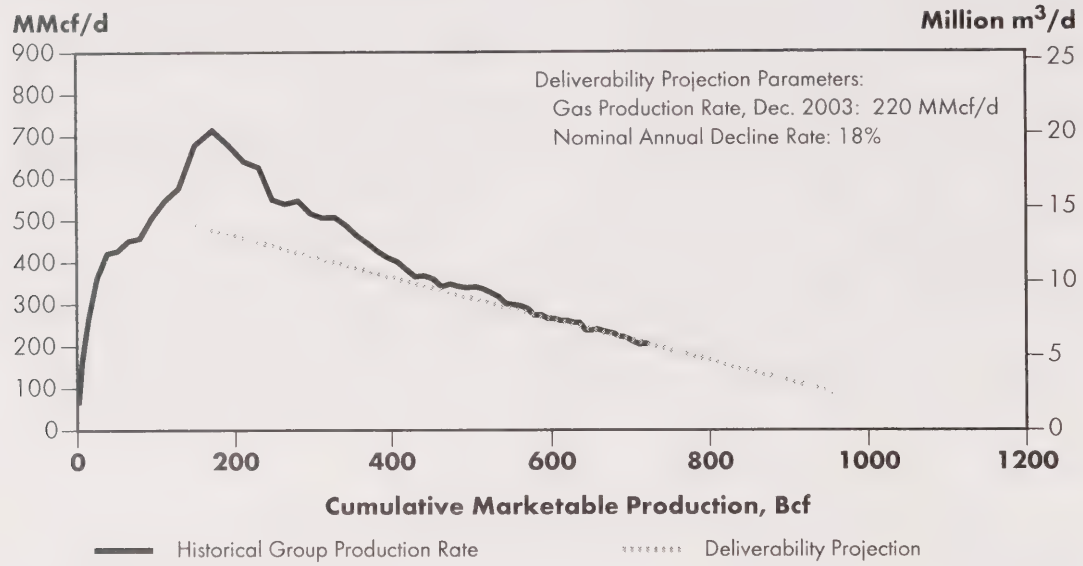
- group deliverability as of December 31, 2003, and
- forward-looking exponential decline rate(s).

The above parameters can be applied to estimate future deliverability for each grouping of existing gas well connections. Figure 3.1 shows the plot generated for the Alberta Foothills Front area for the 1999 connection year as an example of the method used to determine performance parameters for the group. The exponential decline rate is determined as the slope of the line formed by the production history data on the plot of production rate vs. cumulative production. The decline rate determined in this manner is the nominal annual decline rate.

3.1.2 *Future Gas Well Connections*

Deliverability from future gas well connections is expected to form a large component of gas deliverability over the projection period. To estimate deliverability from this source, it is necessary to estimate the number of future gas well connections and the average production characteristics of those future connections. Of the two components, the number of future gas well connections in the WCSB is the more difficult parameter to determine. Drilling levels have been volatile in the past, and are impacted by many factors including market conditions, rig availability, weather and identification of drilling prospects. This section describes the assessment of production performance characteristics of the average future gas well connection, and then covers the methodology used in this EMA for the determination of number of future gas well connections.

Example of Group Production Decline Plot
(Alberta Foothills Front Area, 1999 Connection Year)



Source: Board Analysis of GeoScout Well Production Data

3.1.2.1 Performance of Future Gas Well Connections

To assess the deliverability from future conventional gas well connections in the WCSB, decline analysis was performed on production data representing the "average gas well connection" in each geographic area.

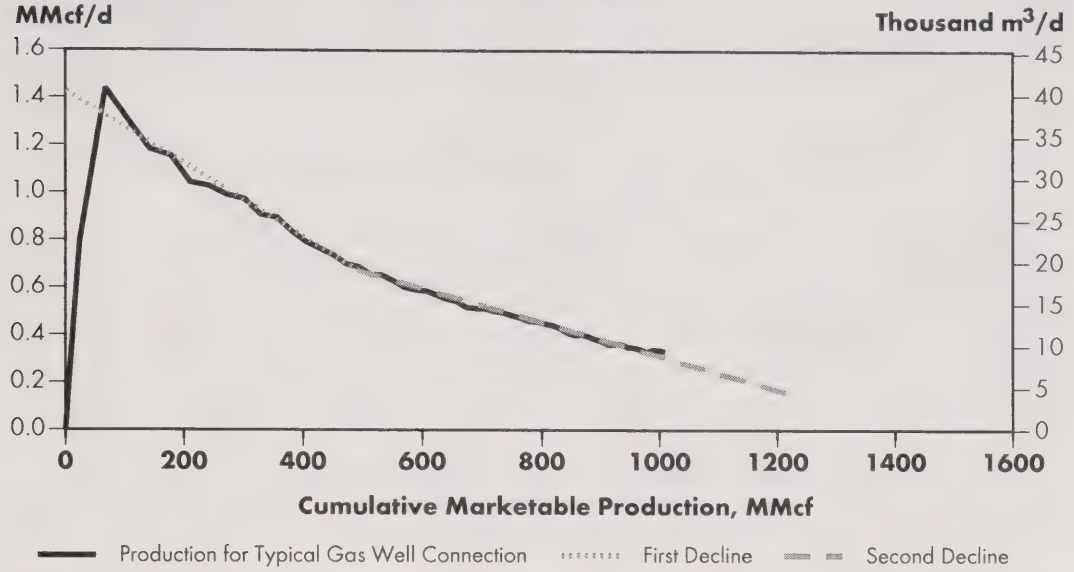
Production decline analysis suggests that the average gas well connection in each area tends to exhibit a steep decline during initial production, which usually lasts for about 17 months, followed by a period characterized by a significantly lower decline rate. To reflect this behavior, the production decline analysis provides:

- initial production rate;
- first decline rate;
- months to second decline rate; and
- second decline rate.

Figure 3.2 provides an example of the type of plot generated in conducting production decline analysis of the average gas well connection. Figure 3.2 shows the analysis for the Alberta Foothills Front area for gas well connections brought on stream in 1999. Plots of this nature were generated for all geographic areas and for all connection years between 1995 and 2003.

The production decline analysis (as shown in Figure 3.2) results in parameters that define the productivity of average gas well connections in past years. The trends evident in well performance in the past years are identified to determine parameters that could be applied to future gas well connections. In assessing the performance parameters of past years, it can be observed that the first decline rate, second decline rate and months to second decline rate were fairly constant within each

Example of Average Gas Well Connection Production Decline Plot
(Alberta Foothills Front Area, 1999 Connection Year)



Source: Board Analysis of GeoScout Well Production Data

geographic area, and thus it is reasonable to apply these historical parameters to future gas well connections in each area. However, the initial productivity of the average gas well generally decreases year after year.

These trends are evidenced by examining the performance of the average gas well connection over the entire WCSB in recent years (Figure 3.3). Graphs showing the average gas well connection performance for recent years and the projected gas well performance for each geographic area are contained in Appendix 1.

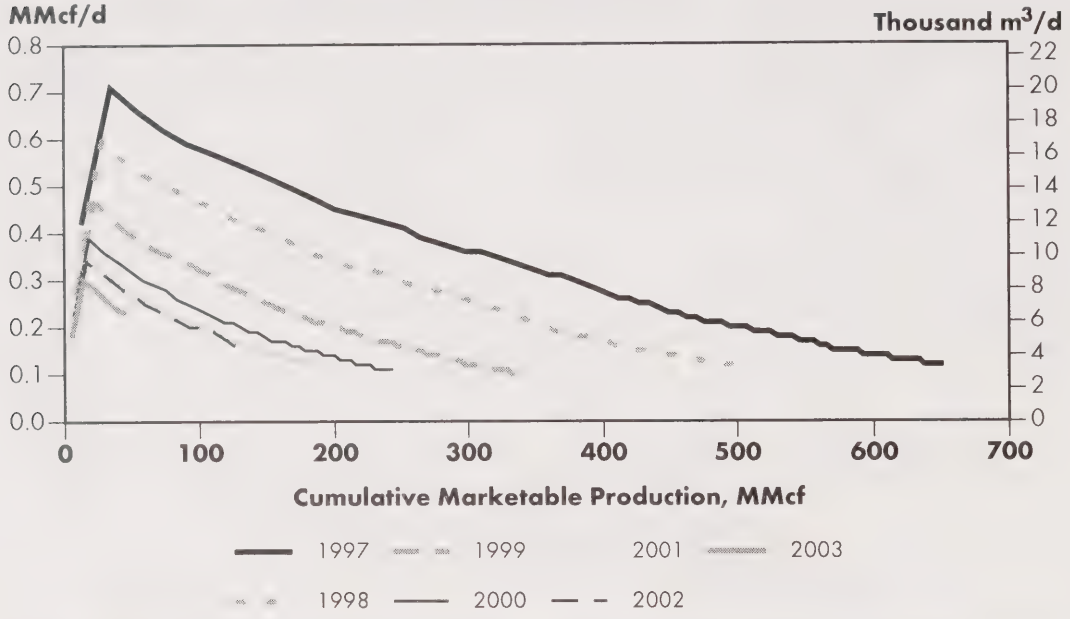
To determine the initial productivity of average gas well connections in the future, the Board examined the trend in initial productivities over time in each area, and projected values for future years that were consistent with the historical trend. Figure 3.4 illustrates the Board's method for selection of initial productivity of gas well connections in 2004, 2005 and 2006.

3.1.2.2 Number of Future Gas Well Connections

Unlike previous EMAs in this series, which incorporated a drilling outlook determined by an industry association, this EMA applies an independent methodology, based on industry cash flow and drilling capacity, to project the level of gas well drilling activity.

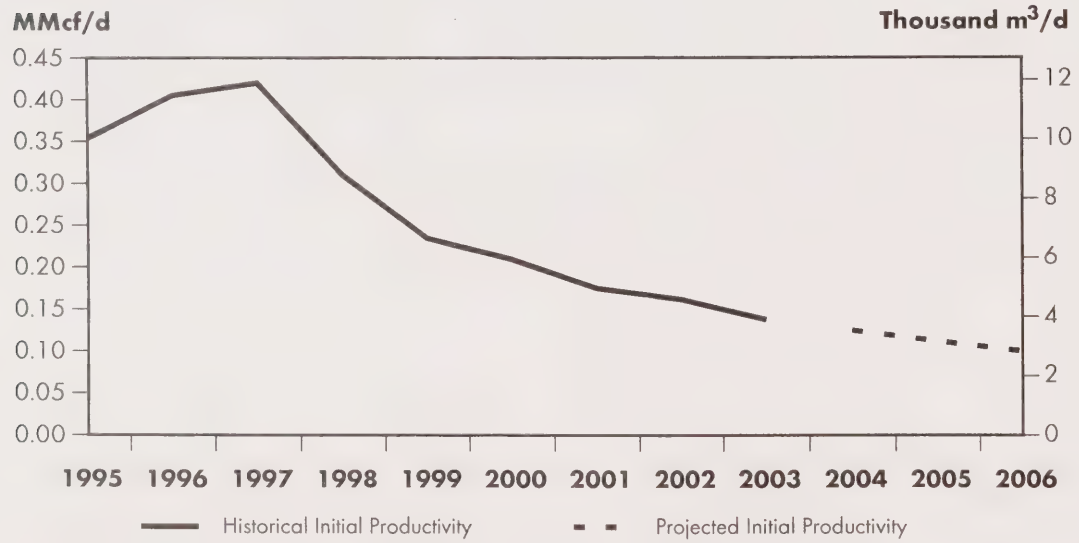
Historical data were examined to develop correlations between drilling levels and gas prices. Factors such as royalty rates, operating costs, re-investment rates, drilling costs, and average drill days per gas well in the various regions were analyzed to determine the level of gas intent drilling that might occur in the WCSB under assumed gas price scenarios. This methodology was discussed with a number of producers who generally found that the approach was reasonable. It was noted that the availability of cash for re-investment was not a constraining factor to gas well drilling in the current environment. This view was confirmed upon applying the cash flow analysis. Under the prevailing

WCSB Average Gas Well Connection Performance



Source: Board Analysis of GeoScout Well Production Data

Example of Initial Productivity of Average Gas Well Connections by Connection Year (Area: Alberta — Southeast)



Source: Board Analysis of GeoScout Well Production Data

market conditions, the level of drilling projected on the basis of cash flow exceeded industry's physical ability to drill gas wells in the WCSB. Appendix 2 shows the derivation of the expected level of gas well directed drill days in each year based on the projected size of the western Canada rig fleet and the likely utilization level as estimated by the Board.

The allocation of gas well drilling days to each area was determined on the basis of historical trends (gas well drilling effort allocated to Southeast Alberta was split further between drilling for conventional gas supplies and drilling for NGC). Dividing the total number of drill days by the average drill days per gas well in each region provided the number of drilled wells. Then, by applying a typical drilling success rate for each region, the number of drilled wells was converted into the number of successful gas wells. The final step was to apply a factor in each region to estimate the number of gas well connections in a year based on the number of successful gas wells.

3.1.3 *Yukon and Northwest Territories*

In the Yukon and Northwest Territories, gas is produced from the Kotaneelee, Cameron Hills and the Liard Plateau gas fields (gas production from Ikhil and Norman Wells is not connected to the pipeline grid and so is not included in this assessment). Due to the small number of producing wells in the territories, a single production decline plot was generated for the aggregate production from Kotaneelee, Cameron Hills and the Liard Plateau to define future deliverability of the existing wells.

Since the Yukon and Northwest Territories have few wells and relatively little production data, a statistical analysis could not be performed in this area for determination of average connection production characteristics. For this area, the Board simply estimated reasonable parameters for future gas well connections based on past well performance in the region.

3.1.4 *Solution Gas*

Solution gas currently accounts for about 8.5 percent of total marketable gas deliverability from the WCSB. To estimate future deliverability of solution gas, production decline analysis was performed to obtain the current production rate and the decline rate for solution gas in each geographic area in Alberta, B.C. and Saskatchewan (with the exception of B.C. Foothills which has no solution gas).

3.2 WCSB – NGC

To estimate deliverability from NGC wells, the same basic relationship is used as in assessing deliverability from conventional gas supplies (that is, future deliverability = deliverability from existing wells + deliverability from future wells). However, since commercial scale exploitation of NGC has occurred only recently, information was sought from producers active in NGC exploitation to complement the limited production data and assist in generating the parameters necessary to estimate NGC deliverability from both existing and future wells.

The available data relating to the drilling of NGC wells was examined and producers who are active in NGC were consulted to estimate the number of future gas wells directed towards NGC. In this analysis, the level of drilling directed towards NGC forms a part of the drilling activity allocated to Southeast Alberta, as discussed in section 3.1.2.1. As with conventional gas wells, the gas well connection trends for NGC wells were examined in order to estimate the number of gas well connections that could be expected relative to the number of NGC gas wells drilled.

3.3 Nova Scotia Offshore

For the Nova Scotia offshore, an exponential decline rate of 30 percent was applied to existing producing wells, based on an average of the decline rates in the three original producing fields.

No new wells are expected in the producing fields, but the addition of field compression is planned for 2006. The parameters used in the compression analysis were obtained in discussions with industry representatives.

Activity is already underway to add a fifth field (South Venture). The expected deliverability from this field was projected from its recoverable resources and by utilizing a production profile based on the other producing fields.

DELIVERABILITY PARAMETERS - RESULTS

4.1 WCSB - Conventional Gas Supply

As discussed in Chapter 3, conventional gas supply in the WCSB is comprised of three components—Existing Gas Wells, Future Gas Wells and Solution Gas. The parameters relating to each of these components are discussed below.

4.1.1 Decline in Production from Existing Gas Well Connections and Solution Gas

Production decline analysis was performed for each geographic area and connection year for existing gas well connections and for each geographic area for solution gas. This analysis resulted in the determination of deliverability as of year-end 2003, and applicable production decline rate(s) from which future deliverability of existing gas well connections and solution gas could be calculated. A table containing all production decline parameters for existing gas well connections and solution gas is included as Appendix 3. Deliverability can be projected from these parameters to be: 457 million m^3/d (16.1 Bcf/d) at the end of 2003, 362 million m^3/d (12.8 Bcf/d) at the end of 2004, 303 million m^3/d (10.7 Bcf/d) at the end of 2005, and 257 million m^3/d (9.1 Bcf/d) by the end of 2006.

4.1.2 Future Gas Well Connections

The analysis in section 4.1.1 concludes that, due to the historically consistent production decline in existing gas well connections and solution gas, approximately 93 million m^3/d (3.3 Bcf/d) of deliverability will have to be replaced annually from new gas wells to maintain production from the WCSB.

4.1.2.1 Performance Parameters for Future Average Gas Well Connections

Considering the large contribution by recent gas well connections to the total WCSB deliverability, the level of deliverability to be expected from future gas well connections is a key factor in assessing future deliverability. The production decline analysis described in Chapter 3 provided the basis for the establishment of performance parameters for future gas well connections.

In general, the first and second decline rate and the number of months to the second decline rate observed in each geographic area have been fairly constant in recent connection years. Consequently, these average gas well performance parameters were applied to future connection years (see Appendix 4).

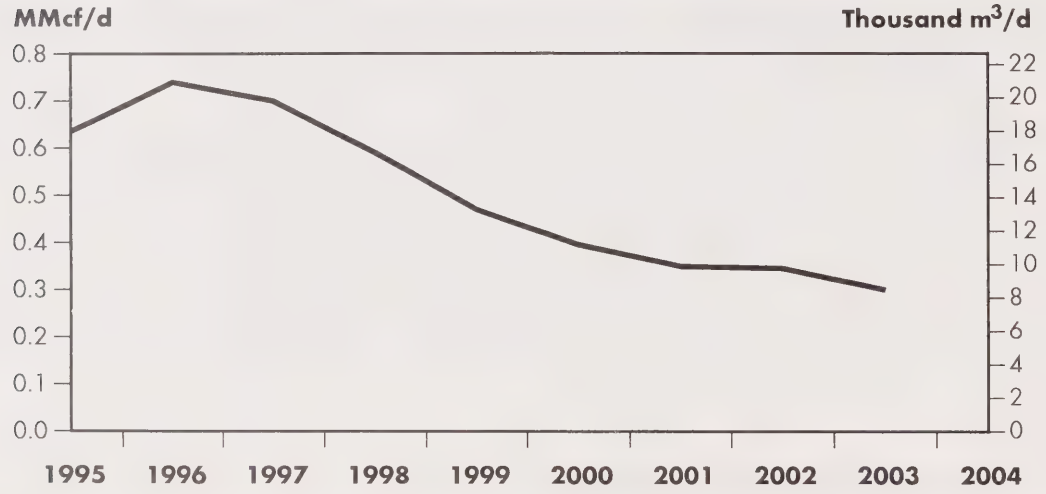
For the initial productivity of gas well connections, the trend varies considerably from area to area (see Appendix 5). In general, the initial productivity of gas well connections continues to decrease from year to year, with smaller decreases apparent in recent years. Figure 4.1 shows the overall trend in initial gas well productivity over time for the entire WCSB.

Specific performance parameters established for future gas well connections in each geographic area are shown in Table 4.1.

4.1.2.2 Number of Future Gas Well Connections

Relatively high gas prices over recent years have spurred high levels of drilling activity. In this connection, the western Canada rig fleet has expanded in recent years and it is expected that the rig count will continue to grow at a steady pace. Figure 4.2. shows the historical and projected western

WCSB Initial Productivity of Average Gas Well Connections by Connection Year

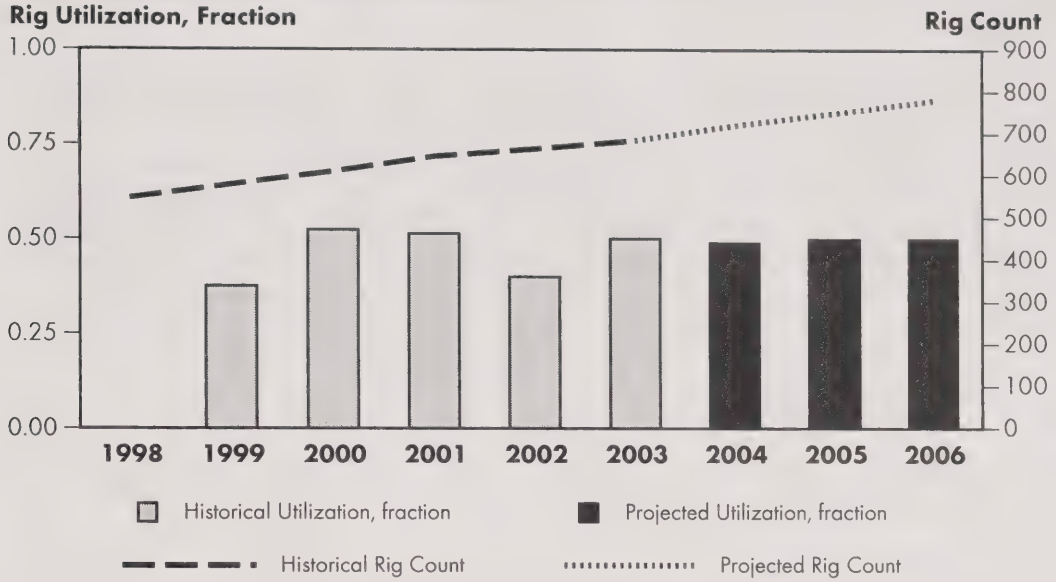


Source: Board Analysis of GeoScout Well Production Data

Production Characteristics for Average Gas Well Connections by Area in 2004, 2005 and 2006

Area	First Decline Rate	Months to Start of Second Decline	Second Decline Rate	Initial Productivity					
				2004 Gas Well Connections		2005 Gas Well Connections		2006 Gas Well Connections	
				$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d
Alberta - Foothills	0.50	12	0.20	49.6	1.75	49.6	1.75	49.6	1.75
Alberta - Foothills Front	0.50	18	0.26	21.2	0.75	19.8	0.70	18.4	0.65
Alberta - Southeast	0.67	15	0.30	3.5	0.13	3.2	0.11	2.8	0.10
Alberta - East Central	0.60	20	0.30	4.5	0.16	4.0	0.14	3.5	0.13
Alberta - Central	0.65	18	0.35	8.2	0.29	7.5	0.27	6.8	0.24
Alberta - Northeast	0.32	24	0.21	6.7	0.24	6.1	0.22	5.7	0.20
Alberta - Northwest	0.55	20	0.32	12.7	0.45	11.9	0.42	11.0	0.39
B.C. - Fort St. John	0.52	20	0.20	25.5	0.90	24.6	0.87	24.1	0.85
B.C. - Fort Nelson	0.45	24	0.20	31.2	1.10	29.7	1.05	28.3	1.00
B.C. - Foothills	0.20	N/A	N/A	113.3	4.00	107.6	3.80	102.0	3.60
Saskatchewan - Central	0.52	20	0.26	6.2	0.22	6.1	0.22	5.9	0.21
Saskatchewan - SouthWest	0.50	16	0.24	2.3	0.08	2.3	0.08	2.3	0.08

Western Canada Rig Fleet and Utilization



Source: CAODC and Precision Drilling (actual rigs at year end), Board projections.

Canada rig count and annual utilization.

Consultation with the drilling industry confirmed that rig utilization over the projection period would be similar to the levels seen in 2001 and 2003, both of which were years with robust market conditions. Based on the expected size of the western Canada rig fleet and the projected utilization level of the fleet, the Board estimates that approximately 15,600 gas wells will be drilled in the WCSB in 2004, 16,900 in 2005, and 17,900 in 2006. Appendix 7 provides graphs of the historical and projected gas well drilling by area.

As discussed in Chapter 3, the number of gas wells is converted into future gas well connections by applying a factor based on the historical relationship between the two parameters. Appendix 6 provides a summary of the historical ratio of gas well connections to gas wells in each geographic

Projected Gas Well Connections by Area

Area	Projected New Gas Well Connections		
	2004	2005	2006
Alberta - Foothills	90	102	111
Alberta - Foothills Front	1,378	1,551	1,709
Alberta - Southeast	6,596	6,524	6,901
Alberta - East Central	952	1,032	1,094
Alberta - Central	1,679	1,808	1,902
Alberta - Northeast	271	257	251
Alberta - Northwest	1,076	1,133	1,164
B.C. - Fort St John	497	540	582
B.C. - Fort Nelson	291	310	327
B.C. - Foothills	24	25	26
Saskatchewan - Central	207	224	238
Saskatchewan - Southwest	2,139	2,309	2,315
Alberta - NGC	737	1,425	1,785
Total WCSB (Excluding Yukon and NWT)	**15,937**	**17,240**	**18,405**

area, and shows the ratio chosen in each area that is applied over the projection period. Based on these factors, the Board's projection of gas well connections by area is shown in Table 4.2. The Board projects that gas well connections would amount to 15,900 in the WCSB in 2004, 17,200 in 2005 and 18,400 in 2006.

The historical allocation of drilling effort in the WCSB has also been examined and it was observed that the western side of the WCSB, particularly B.C., has been attracting a slightly greater allocation of total basin drilling effort in recent years (see Appendix 8). In general, the Board's projected allocation of drilling effort to the various areas of the WCSB is consistent with this recent historical pattern. However, the Board projects that the Fort Nelson and Fort St. John areas of B.C., and the Foothills area of Alberta will continue to attract a slightly greater share of gas drilling in the basin than in the past, while Northeast and Northwest Alberta will attract a slightly smaller share of basin drilling activity.

4.2 WCSB - NGC

4.2.1 *Existing NGC Connections*

NGC deliverability as of the end of 2003 was about 2.1 million m^3/d (75 MMcf/d). As noted earlier, NGC production differs from conventional gas production in that NGC production declines more slowly. As such, a zero decline has been applied to existing production over the 12 month period to December 31, 2004, with an annual decline rate of 10 percent applied thereafter.

4.2.2 *Future NGC Connections*

Based on consultations with industry and an examination of NGC development trends, the number of NGC wells projected to be drilled over the projection period are 1,100 wells, 1,900 wells and 2,100 wells in 2004, 2005 and 2006 respectively. The approximate number of NGC connections resulting from these wells is projected to be 750 in 2004, 1,400 in 2005 and 1,800 in 2006. Based on industry consultations and consideration of available production data, initial productivity for the average NGC connection is estimated at 2.8 thousand m^3/d (100 Mcf/d). The Board projects no decline in average well production for the first 24 months of production, with a nominal annual decline rate of 10 percent thereafter.

4.3 Nova Scotia Offshore

Nova Scotia offshore deliverability is currently sourced from four fields with the fifth estimated to commence production at the start of 2005. The four producing fields are considered to have all required gas well connections in place as of the end of 2003. Total deliverability at the end of 2003 was about 12.8 million m^3/d (450 MMcf/d).

The new South Venture field is estimated to contain about the same recoverable resources as the Alma field. Consequently, the Alma field development and production profile has been used as a pattern for the estimate of South Venture. This would involve two gas wells and connections in the South Venture field. Initial deliverability from South Venture is estimated at 3.5 million m^3/d (124 MMcf/d). Annual production declines from SOEP are estimated at 30 percent in accordance with the production history of the three original fields.

DELIVERABILITY OUTLOOK

The outlook for Canadian gas deliverability is shown in Table 5.1 by geographic area. Deliverability is reported on an average annual basis, rather than at year-end, to provide a more representative estimate for each year. The table shows annual average production for 2003, and expected annual average deliverability for 2004, 2005 and 2006 for each component. Canadian annual average deliverability is expected to increase slightly from 469 million m^3/d (16.6 Bcf/d) in 2003 to 477 million m^3/d (16.9 Bcf/d) in 2006. While the productivity of the average new gas connection continues to decrease, the overall rate of decrease has slowed; hence increasing drilling levels enable slightly increasing production.

5.1 WCSB - Conventional Gas

The deliverability of conventional gas from the WCSB is expected to be relatively flat over the projection period at approximately 456 million m^3/d (16.1 Bcf/d). At the same time, deliverability of conventional gas from the largest producing province, Alberta, is expected to decline over the projection period from approximately 365 million m^3/d (12.9 Bcf/d) to 353 million m^3/d (12.4 Bcf/d). Decreases in production are expected to occur in the Northeast and Northwest areas, which in aggregate are expected to fall from an annual average of 85 million m^3/d (3.0 Bcf/d) in

TABLE 5.1

Canadian Gas Deliverability Outlook by Area

Area Name	Average Annual Production							
	Historical		Projection					
	2003		2004		2005		2006	
	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d
Alberta - Foothills	16.57	585	17.64	623	18.69	660	19.84	700
Alberta - Foothills Front	124.00	4,377	125.12	4,417	123.85	4,372	123.32	4,353
Alberta - Southeast	75.82	2,677	79.02	2,789	77.95	2,752	75.65	2,671
Alberta - East Central	18.27	645	18.20	642	18.07	638	17.67	624
Alberta - Central	45.08	1,591	46.39	1,638	46.28	1,634	45.63	1,611
Alberta - Northeast	28.64	1,011	25.24	891	22.24	785	19.64	693
Alberta - Northwest	56.56	1,996	53.93	1,904	52.47	1,852	50.71	1,790
B.C. - Fort St John	37.53	1,325	36.17	1,277	37.74	1,332	39.72	1,402
B.C. - Fort Nelson	21.84	771	23.72	837	25.59	903	27.15	958
B.C. - Foothills	10.46	369	11.20	395	11.86	419	12.37	437
Saskatchewan - Central	4.87	172	4.98	176	5.06	178	5.12	181
Saskatchewan - Southwest	12.91	456	14.39	508	15.38	543	16.30	576
Saskatchewan - Southeast	0.83	29	0.83	29	0.82	29	0.81	29
Yukon and Northwest Territories	2.35	83	1.86	66	1.88	66	2.12	75
Total WCSB Conventional	**455.76**	**16,088**	**458.68**	**16,191**	**457.89**	**16,164**	**456.05**	**16,099**
Alberta - NGC	1.34	47	3.26	115	6.28	222	10.64	376
Total WCSB	**457.10**	**16,136**	**461.93**	**16,306**	**464.17**	**16,385**	**466.69**	**16,474**
East Coast Offshore	12.25	432	11.47	405	12.08	426	11.20	395
Total Canada	**469.34**	**16,568**	**473.40**	**16,711**	**476.25**	**16,812**	**477.89**	**16,870**

2003 to 70 million m^3/d (2.5 Bcf/d) in 2006. While the Alberta Foothills area is expected to increase slightly, the large contribution from the Foothills Front, Southeast Alberta and Central Alberta is expected to be fairly stable for the projection period at an aggregate of approximately 245 to 250 million m^3/d (8.6 to 8.8 Bcf/d).

Deliverability is expected to increase in all three areas of B.C. over the projection period, resulting in total B.C. production increasing from an annual average of 69.8 million m^3/d (2.5 Bcf/d) in 2003 to an annual average of 79.5 million m^3/d (2.8 Bcf/d) in 2006.

Total deliverability from Saskatchewan is also projected to increase slightly over the projection period from an annual average of 18.6 million m^3/d (0.7 Bcf/d) in 2003 to 22.3 million m^3/d (0.8 Bcf/d) in 2006.

Deliverability in the Yukon and Northwest Territories is expected to slip by 20 percent in 2004 and 2005, but begins to recover in 2006 as new wells are added.

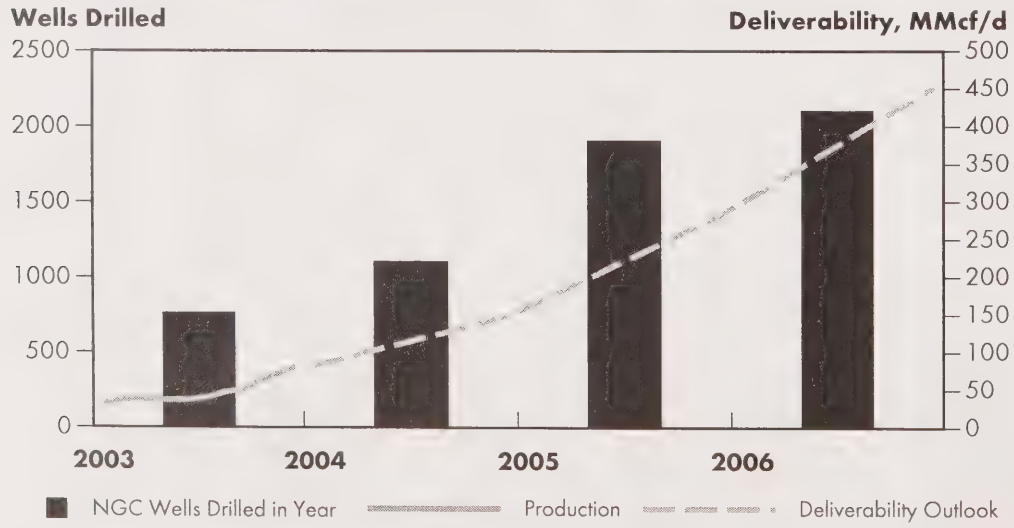
5.2 WCSB - NGC

NGC is the fastest growing category of deliverability in the assessment. NGC deliverability is expected to rise by a factor of six over the three year period from 2.1 million m^3/d (75 MMcf/d) at the start of 2004 to 12.7 million m^3/d (450 MMcf/d) by the end of 2006. All of the production is expected to be from the Horseshoe Canyon coals of south central Alberta.

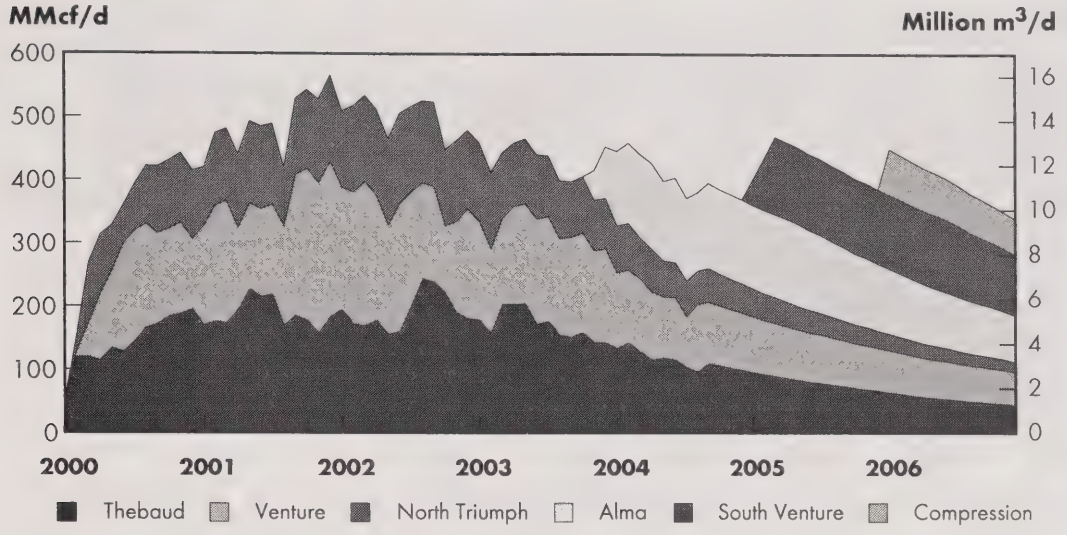
The expected growth in deliverability requires significant increases in NGC activity. Prior to 2004, only about 700 NGC wells had been connected in western Canada. In 2004, NGC activity is expected to result in 1,100 new wells drilled; this could have been higher if not hampered by wet weather. The increases in NGC activity are expected to continue over the subsequent years to reach 2,100 wells drilled in 2006 (see Figure 5.1, NGC Drilling and Deliverability).

Despite the rapid rise in NGC deliverability, its contribution to overall Canadian deliverability remains relatively modest by 2006 at roughly 2.2 percent.

NGC Drilling and Deliverability



Nova Scotia Offshore Deliverability Outlook



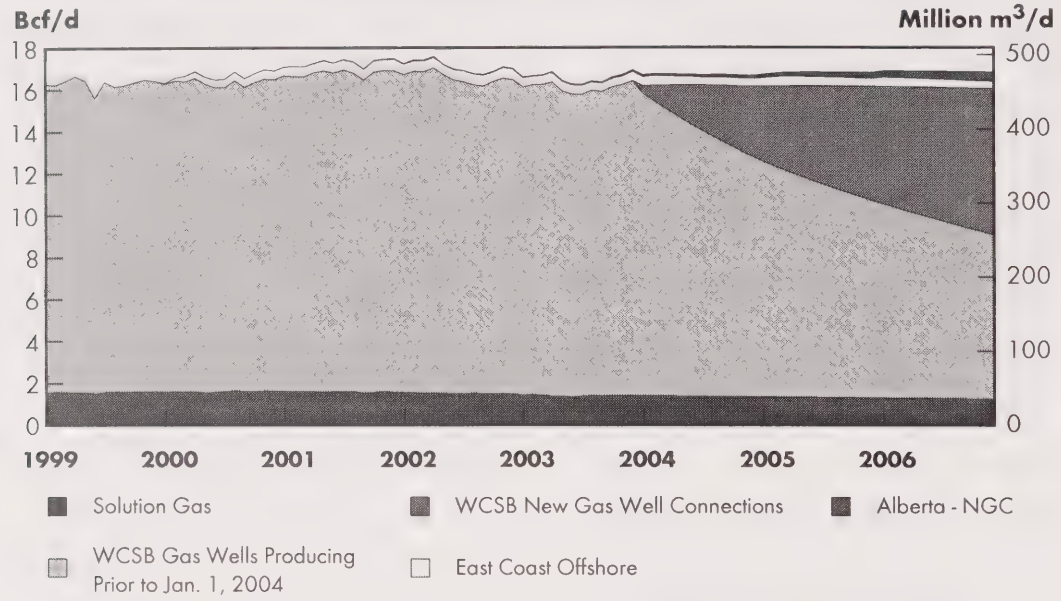
5.3 Nova Scotia Offshore

As illustrated in Figure 5.2, the estimate of deliverability from the SOEP through 2006 incorporates ongoing natural declines in the four producing fields and the addition of the South Venture field at the start of 2005. Offshore compression is expected to be added in 2006 to enhance production from the original fields. These additions are expected to maintain production around 11 million m^3/d (400 MMcf/d) for most of the period to mid-2006. However, the significant variability in deliverability over the period will continue to present challenges to markets in the area.

5.4 Total Canada

Figure 5.3 portrays the outlook for total Canadian gas deliverability and the major segments of gas supply over the projection period. Total Canadian production is expected to increase slightly over the projection period. Production from WCSB conventional gas supply is expected to be sustained at approximately recent levels, with the contribution from Alberta NGC increasing over the projection period. Production from the Nova Scotia offshore is somewhat variable, but is expected to average around current levels for most of the projection period.

Outlook for Canadian Gas Deliverability



Conclusions and Implications

The Canadian upstream industry has continued to respond to the high levels of natural gas prices since 2003. Gas prices in 2004 have been particularly robust. Based on rig activity, the number of gas wells drilled is expected to increase by three percent over the record achieved in 2003. Moreover, the increase in drilling activity in 2004 would have been even higher if wet weather conditions had not hampered the movement of rigs.

The effective decline rate for production from existing wells is expected to remain at around 21 percent per year. This means that new connections would need to replace over a fifth of the previous year's output to keep overall production constant.

The trend of lower initial productivity in new WCSB gas wells is continuing. Consequently, to offset production declines from producing wells, the number of new gas connections must rise each year to maintain production levels. The Board expects that the number of gas wells drilled would need to increase from 15,100 in 2003 to about 15,600 in 2004 and 17,900 by 2006 in order to maintain current production.

With natural gas prices expected to remain above $4.75/GJ ($5.00/Mcf), there appears to be sufficient economic gas prospects and available cash flow to maintain Canadian gas production. The outlook from this analysis indicates average annual Canadian gas deliverability under these conditions would rise slightly from 469 million m^3/d (16.6 Bcf/d) in 2003 to 477 million m^3/d (16.9 Bcf/d) in 2006.

The expected increase in deliverability is largely due to the growth in production of NGC. Conventional gas deliverability in western Canada would remain relatively flat over the outlook period. Gains in conventional gas deliverability from the western side of the basin (Alberta Foothills and B.C.) plus some growth in Southwest Saskatchewan are offset by reductions in deliverability from Northeast and Northwest Alberta. Alberta's Foothills Front and Southeast remain the mainstays of Canadian gas deliverability, together representing roughly 42 percent of total production in 2006. Deliverability from these two critical regions is projected to remain fairly constant over the period. Nova Scotia offshore deliverability is somewhat variable over the period while averaging around 11 million m^3/d (400 MMcf/d).

The expectation of an 8.1 million m^3/d (0.3 Bcf/d) increase in overall Canadian deliverability over the three year projection period compares to an estimated 14.2 million m^3/d (0.5 Bcf/d) decrease estimated in the December 2003 edition of this report. The main reason for the decline in the previous assessment was an expectation of lower gas prices leading to a less aggressive gas well drilling outlook than is contemplated in this EMA.

Implications

The Canadian upstream industry will need to continue increasing drilling activity each year to offset declines in the productivity of the remaining resources. As long as gas prices remain strong, it appears that the industry will have sufficient cash flow to make the required investments to maintain deliverability or even achieve modest growth. Challenges to be overcome include the availability of sufficient personnel to operate the increasing number of rigs and retaining sufficient geoscience and engineering professionals to identify the additional prospects.

Should Canadian natural gas prices slip back to the $3.80/GJ ($4.00/Mcf) range, the ability to maintain deliverability would be compromised. With fewer economic prospects and less cash flow to fund drilling activity, a sustained drop in prices would lead to declining Canadian gas deliverability.

Improvements to drilling rig utilization, perhaps through efforts to reduce the seasonal variability in activity, could result in more drilling than is contemplated in this study and a further modest increase in deliverability. To benefit from increased drilling utilization, the industry must also maintain its ability to identify additional drilling prospects.

High levels of activity will continue to exert cost pressure on the upstream industry. Escalating costs for drilling, operations, land and materials have all contributed to higher overall industry expenses. Thus far, increases in gas prices have more than offset these higher costs. However, should prices weaken while costs continue to rise, some of the projected deliverability may not provide sufficient returns to warrant its inclusion.

NGC accounts for much of the potential growth in Canadian gas deliverability. The development of NGC could involve a large number of wells and will continue to require close consultation with landowners and others affected by NGC operations to ensure ongoing access to this important resource.

The expected variability in deliverability from Nova Scotia's offshore will continue to present challenges to markets in the area over the projection period as consumers will need to adjust to supply fluctuations.

Average gas well connection	An average gas well connection represents the average producing characteristics of ALL gas well connections for a geographic area and connection year. Production data for the average gas well connection for any grouping (geographic area/connection year) is calculated as: [total production for all gas connections in grouping, summed by normalized production month]/ [the total number of gas well connections in the grouping].
Connection Year	The year associated with the "On Production Date" for a Gas Well Connection or an Oil Well Connection.
Connection	A geological horizon within a well for which oil and/or natural gas production is reported.
Conventional Gas Supply	Refers to gas in the WCSB from all sources other than NGC.
Decline Rate	A term used to describe the decrease in production rate over time as a resource is depleted. There are various ways of expressing Decline Rates, and in this report **exponential decline** is the type used to define well production decline characteristics. With exponential decline, a straight line is exhibited when production rate is plotted against cumulative production, and the slope of the line defines the **nominal** decline rate (in this report it is expressed as fraction per year). Another way of expressing Decline Rate is in terms of **effective** decline rate, which is the decrease in production divided by the initial production rate. The effective decline rate can be converted into nominal terms using the following equation: **nominal decline rate = -ln(1 – effective decline rate)**
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Drill day(s)	The number of days that a rig is engaged drilling a well, calculated as Drilling Completion Date minus the Spud Date plus 1.
Gas Well Connection	A geological horizon within a Gas Well for which natural gas production has been reported. If the Well Connection has both oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.

Gas Well	A well bore with one or more geological horizons capable of producing natural gas.
Marketable Gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
NGC	Natural gas from coal.
Normalized production month	For any gas well connection and for any production month, the normalized production month is the number of months since the first month of production for the gas well connection.
Oil Well Connection	A geological horizon within a well for which oil production has been reported. If the Well Connection has both oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
Projection Period	January 1 2004 to December 31 2006.
Rig Utilization Level(s)	In this EMA, rig utilization applies to drill rigs in western Canada and is calculated as: [total number of drill days for all wells completed drilling in a year]/ ([estimated number of drill rigs comprising the Rig fleet in a year] * [days in year]).
Solution Gas	Natural gas that is produced from an Oil Well Connection.

Available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityCanada2004_2006_e.htm